2

Chapter 2 – PTF Costs and Financing Mechanism

Expected Capital Costs

The Commission has an obligation to review the potential costs of a generation project proposed by a Wisconsin utility in order to examine the potential impact the project might have on utility customers or ratepayers. This chapter will describe the estimated cost of the ERGS project, the assumptions and uncertainties contained in those estimated costs, and the expected financial impact on WEPCO customers if the entire project or portions of it are approved. The estimated capital costs include the generating units, transmission interconnection (but no upgrades to the transmission system to facilitate power dispatch), and shared facility improvements (such as water supply and coal handling and delivery).

WEPCO provided the costs for the ERGS as part of its overall PTF application. However, the costs provided for ERGS are not as certain as those provided for the Port Washington units.[12] The costs provided for the SCPC units are somewhat uncertain and the cost for the IGCC unit is even less certain. Thus, the estimated costs for the ERGS are on a "cost-plus-up to 10 percent cap" basis, rather than a strong "firm" basis like the Port Washington costs.[13] In its May 2003 direct testimony, WEPCO indicates that projects would be capped at no more than 10 percent above the construction estimates for the coal facilities, thus placing some of the risk of any cost overruns on ratepayers, but not all of the risk. This represents an improvement for ratepayers over the initial proposed treatment which had no cap.

WE Power has indicated specifically that "because few comparable coal-based facilities have been built recently, the risk that actual costs may deviate from estimated costs is greater for the ERGS proposal than for the Port Washington project." In addition, labor costs make up a greater share of costs for the ERGS project, and equipment costs are inherently more difficult to estimate for coal-based units than for gas-based units.[14] The implication of these cost uncertainties for ratepayers is discussed later in this chapter.

WEPCO estimates that the costs for the SCPC units would range between plus or minus 10 percent from those estimated, with a higher uncertainty for the IGCC project costs.[15] In addition, IGCC cost estimates are

[12] Introduction and Application booklet, p. 12 of the CPCN application and Volume 1, Enclosure 8, page 1.

[13] In the Port Washington CPCN, WE Power indicated that it would bear the risk of cost overruns unless the overruns were due to unpredictable occurrences beyond WE Power's control or changes in the general inflation level. The Commission accepted and approved such a "hold-to" treatment for the Port Washington combined-cycle units. Examples of unpredictable occurrences beyond WE Power's control included changes in laws or government regulations and Act-of God or similar events.

[14] "Power the Future--Application to the Public Service Commission of Wisconsin," Application, page 13, February 15, 2002.

[15] Response to 1-SUP-156.

less certain because coal-based IGCC plants in the 500+ MW range have not been built anywhere in the world. Estimated costs for the ERGS project on a per unit basis are listed in Table 2-1. The total cost for the ERGS proposal is estimated to be about $4,314,995,000.

The cost estimates provided by WEPCO were utilized in the EGEAS modeling discussed in Chapter 4. For the SCPC and IGCC generating units, construction cost estimates of $1,415/kW and $1,739/kW were utilized respectively for the economic evaluation.[16]

Table 2-1 ERGS estimated construction costs on a per unit basis

Item	Unit 1 SCPC (2003)	Unit 2 SCPC (2003)	Unit 3 IGCC (2003)
Generating Unit (2003 $)	922,140,000	623,470,000	843,394,000
Shared Facilities	335,750,000	28,220,000	59,171,000
Escalation	125,412,000	78,594,000	147,118,000
Carrying Cost	261,300,000	275,200,000	298,900,000
Retirement Cost	138,330,000	73,028,000	104,968,000
TOTAL	1,782,932,000	1,078,512,000	1,453,551,000
TOTAL, 3 UNITS	4,314,995,000		

* Each unit has $13 million included for additional train costs.
** Escalation is for general inflation as measured by the GDP price deflator.
*** Carrying costs represent the interest on the capital invested in the project.
**** Retirement costs include amounts necessary to tear down the facility.

Production costs for electric generation consist of the capital dollars to build the plant, fuel procurement, and the Operating and Maintenance (O&M) expenses. Each of these costs is described in more detail below.

Financing mechanism

In its supply resource planning, WEPCO considered utility-owned generation (i.e. traditional rate-based generation), procurement from wholesale merchant plant suppliers (i.e. independent power producers), and leased generation from a public utility affiliate. After reviewing these three approaches, WEPCO decided to pursue the leased generation financing approach for both the combined-cycle units at Port Washington and the coal-fired facilities designated as the ERGS and located near the existing Oak Creek Power Plant.

The leased generation contract for the ERGS consists of three leases, a Facility Lease, a Ground Lease, and Ground Sublease. A set of these three leases would be required for each of the three units proposed for the ERGS. At this time, only the leases for the first SCPC unit have been provided to the PSC for review. These leases and their financial terms and ratepayer impacts are discussed later in this chapter.

Technology cost assumptions – SCPC units

WEPCO is proposing to use bituminous coal as the primary fuel source at an estimated cost premium of 3.5 percent more than if it burned sub-bituminous coal. The additional cost offers advantages of improved mercury collection and higher efficiencies[17] (thus less CO_2 production). Bituminous coals, from the eastern

[16] DR-006 provided original supporting documentation for levelized lease payments. Al Mihm's testimony provided the latest $/kW costs.
[17] Response to 1-SUP-013.

U.S., have higher heating values due to more fixed carbon. Subbituminous coals, from the western U.S., have higher ash and moisture content.

The technology for the SCPC units is considered mature and the estimated costs should be relatively stable. Roughly 1,000 units are operating with coal as a primary fuel source and it is estimated that 40 units within the U.S. have incorporated the SCPC technology since 1960.[18]

Since the PTF application was initially filed, WE Power has received bids for the Engineer, Procure, and Construct (EPC) contract for the SCPC units. Bechtel Power Corporation has been selected as the lowest evaluated bidder. WEPCO has indicated a change from the original cost estimates of $1,263/kW in 2001 dollars to $1,400/kW in 2003 dollars.

Items that impacted the original estimate provided by WEPCO include:

- The need to remove a portion of the bluff for plant siting.
- The additional cost for the water intake being tunneled 9,000 feet into bedrock.[19]
- The estimated cost for a fabric final filter after the electrostatic precipitator (if required).
- The estimated cost of $20 million for a coal shed over the active coal pile.[20]
- Construction of an underpass at Six Mile Road at a cost estimated at $5 million.[21]

Items that have not been considered part of the construction cost include:

- Recently negotiated annual payments to Oak Creek similar to that paid to Port Washington.[22]
- Transmission system impacts.

Technology cost assumptions - IGCC Unit

The estimated cost for the IGCC unit is not as refined as that for the SCPC units. A request for bids for an EPC contract for the IGCC plant has not been issued and likely will not be issued before a CPCN decision occurs. There is little historical information to determine the estimated IGCC cost and the 2011 commercial operation date is too far into the future to develop a more reliable estimate with increased price certainty.

IGCC technology has been demonstrated commercially at only two sites within the U. S., both for a nominal 250-MW size plant. The cost for one of those plants, the Wabash River Plant in Indiana, was $417 million for a 262-MW facility (in 1995 dollars) or $1,591/kW.

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18 http://www.fe.doe.gov/coal_power/special_rpts/market_systems/marketbased_systems_appendices.pdf page 11.

19 Response to 1-SUP-093.

20 WEPCO increased this cost from $5 million to $20 million in its comments on the draft EIS.

21 Grade Separation Feasibility Studies… by Benesch.

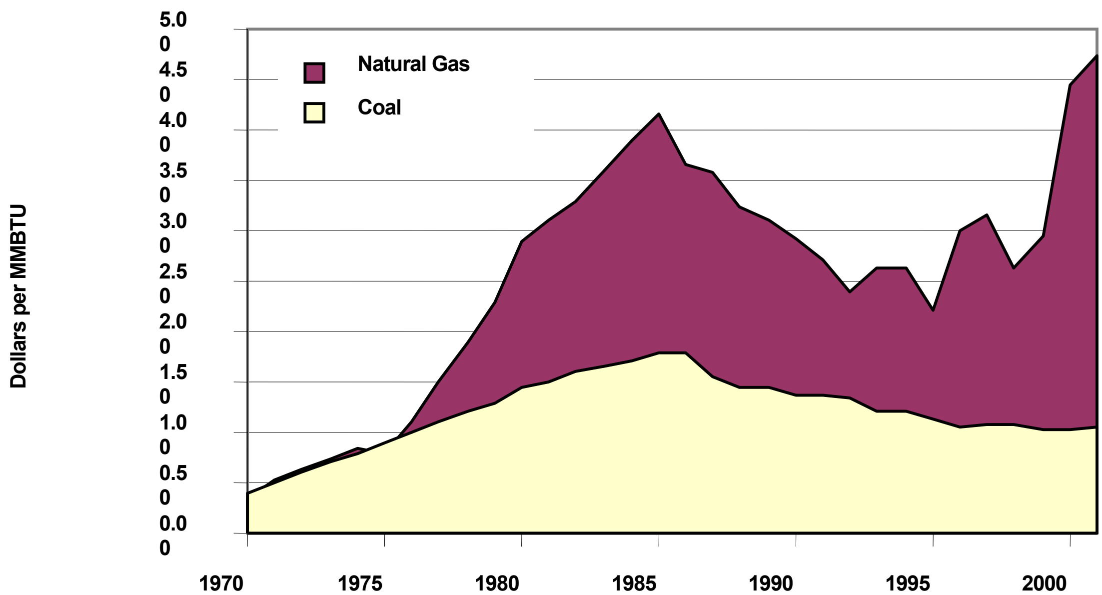
22 The Commission approved an annual payment of $500,000 to the city of Port Washington after it approved the construction of two 515 MW natural gas-fired combined-cycle plants to replace the existing 320 MW of coal-fired generation currently on-site. Recently WEC and WEPCO agreed to pay Oak Creek the following amounts: $1.5 million per year after the start-up of unit 1 (SCPC); an additional $750,000 at the start-up of unit 2 (SCPC); and an additional $250,000 at the start-up of unit 3 (IGCC).

Fuel cost assumptions

WEPCO forecasts coal prices at a cost of $1.35 per mmBtu (or $26.00 per ton) and expects that this cost would increase at an annual growth rate. In its coal price estimates, WEPCO applies nominal increases (near inflation levels) for 2004 and beyond. There is little price volatility in its forecast from year-to-year after 2004. Thus, WEPCO's forecasted coal prices appear to be conservative, and appear not to unduly favor coal over use of other fuels. Figure 2-1 shows that historically, the price of coal has been quite stable for Wisconsin utilities, especially compared to the price of natural gas. The volatility of natural gas prices is discussed in Chapters 4 and 5.

WEPCO assumes that the cost of coal delivered by rail or barge is comparable for bituminous coal.[23]

Figure 2-1 Price of coal versus natural gas for Wisconsin utilities



Operation and maintenance

Costs estimated by WEPCO are broken into fixed or variable operations and maintenance expenses (O&M). Fixed O&M expenses for the SCPC units are estimated at $20.07/kW/year. This includes plant staffing, insurance, and some other equipment and contract labor maintenance costs. Variable O&M expenses for the SCPC units are estimated at $ 2.01/MWH. This estimate includes the equipment, material, and contract labor costs associated with equipment maintenance.

Fixed O&M expenses for the IGCC unit are estimated at $33.44 /kW/year. This also includes plant staffing, insurance, and some other equipment and contract labor maintenance costs. Variable O&M expenses for

[23] Response to 1-SUP-206.

the IGCC units are estimated at $ 0.82/MWH. This estimate includes the equipment, material, and contract labor costs associated with equipment maintenance.

The O&M costs for the SCPC units are comparable with other coal-fired units operating in Wisconsin and are slightly lower than estimates from the Energy Information Administration (EIA), an office in the U.S. Department of Energy. The IGCC costs are similar to EIA estimates since limited experience is available from other plants.

Retirement costs

Future retirement costs for the proposed units would be collected as part of the annual lease payments. Net salvage factors of 10 percent of the estimated project cost for these coal-fired units was utilized as part of the lease payment.

Projected transmission costs

American Transmission Company (ATC) completed the Generation Interconnection Study Report for the ERGS facilities (IC012) in December 2001. The Final Summary Report Revision 1 was issued July 17, 2002. This report presented and summarized the results of the stability, thermal and fault duty studies for all three phases of the ERGS proposal. A detailed cost break down and description of the requirements for each stage can be found in Chapter 6.

The total transmission costs, associated with all three coal units, are expected to be $266,214,753 in 2007 dollars. WE Power would pay for the system improvements up to the point where the interconnections reach the common network side of the high voltage system, which is 345 kilovolts (kV) in this case. Beyond that point, the network transmission costs would be covered by ATC. ATC would recover its costs through transmission tariffs which are approved by the Federal Energy Regulatory Commission (FERC). The three phases of the ERGS proposal have associated transmission costs as follow:

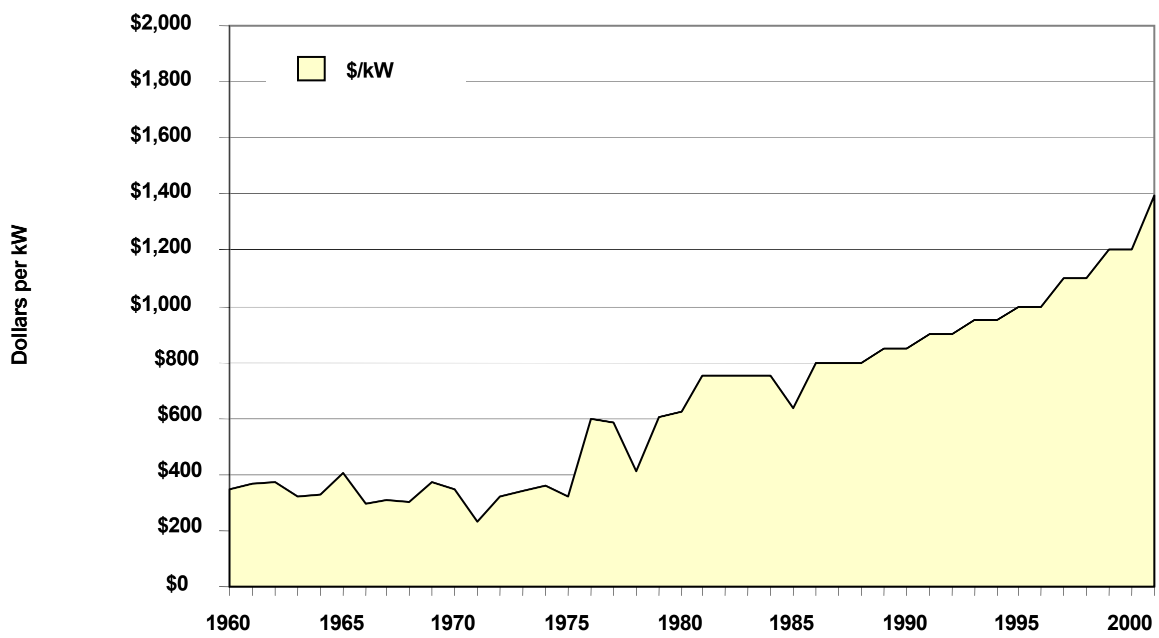
Phase 1 – 650 MW in 2007	Project Cost (2007 $)
System Reinforcements for Stability (Required)	94, 989,991
System Reinforcements for Short Circuit (Required)	2, 435,391
System Reinforcements for Thermal (Optional)	20, 288,167
Total Phase 1	**117,713,549**
Phase 2 – 1,300 MW total in 2009	
System Reinforcements for Stability (Required)	46,338,542
System Reinforcements for Short Circuit (Required)	0
System Reinforcements for Thermal (Optional)	0
Total Phase 2	**46,338,542**
Phase 3 – 1,950 MW total in 2011	
System Reinforcements for Stability (Required)	88,810,206
System Reinforcements for Short Circuit (Required)	7,654,086
System Reinforcements for Thermal (Optional)	5,700,370
Total Phase 3	**102,164,662**
Grand Total	**$266,216,753**

Uncertainties inherent in the estimated costs

ATC performs interconnection studies based on requests that are placed in a queue. When it performs a new generation interconnection study, ATC assumes that the facility interconnections requested prior to the case at hand, are in place. It assumes that the plants have been built and are interconnected to the primary transmission network.

In Wisconsin, several generation projects that preceded the ERGS proposal in the ATC queue have been cancelled, or indefinitely delayed. At the time that the initial interconnection study for the ERGS was completed, there were other units in the Midwest queue ahead of Elm Road, including IC001 (Midwest Power – Germantown), IC003 (Badger Gen – Kenosha), and four generating units in northern Illinois. These generating plants were all assumed to be interconnected and operating when the transmission studies for the ERGS were being done. Since that time IC001 and IC003 have dropped out of the queue or have been terminated, as well as three out of the four Illinois plants. Thus, the transmission improvements designated as needed for transmission service (thermal options) may no longer be required or may be somewhat different. More discussion about these transmission improvements and updated transmission studies can be found in Chapter 6.

Figure 2-2 Construction cost per kW for Wisconsin coal plants since 1960 (cost increases after 1985 are based solely on inflation since no plants were actually built between 1985 and 2000)

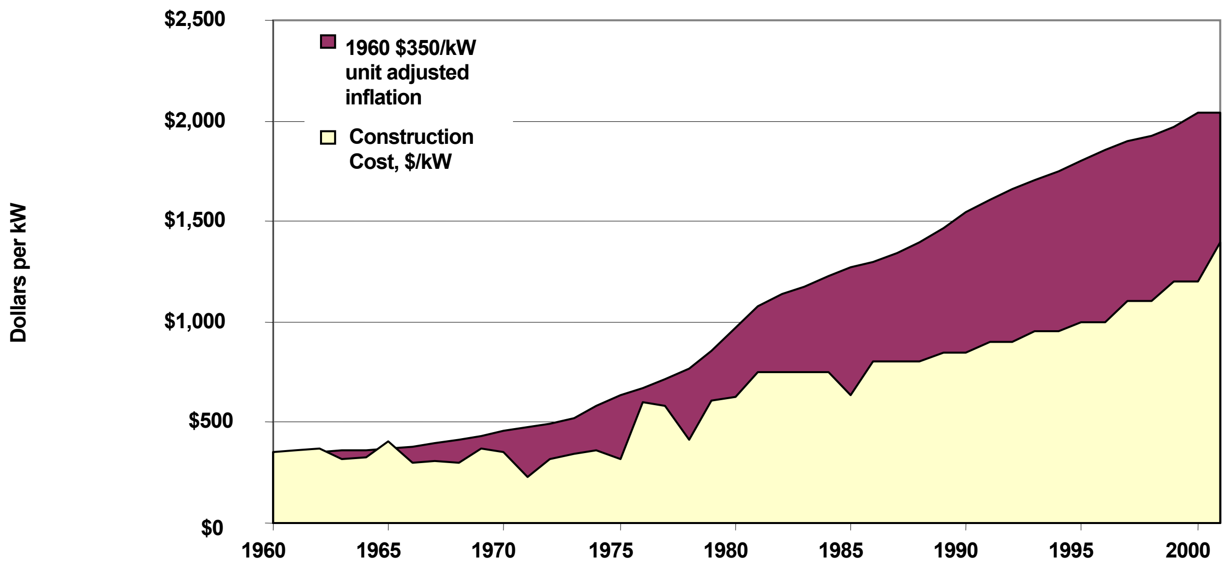


Costs of previous coal-fired generation plants

Estimated costs and actual costs for approximately 20 coal-fired generating units built in Wisconsin since 1960 were reviewed to determine the potential for cost overruns in the ERGS project. A comparison on a per unit basis for Wisconsin coal plants built since 1960 is shown in Figure 2-2. For power plants, the per unit basis is construction cost per kW ($/kW). Costs over the past ten years, when no coal units were actually built in Wisconsin, were estimated based on inflation rates.

Costs have increased on a per unit basis but less than inflation. To further illustrate how costs have changed with time, the construction costs on a per unit basis are compared to the inflation rate as shown in Figure 2-3.

Figure 2-3 Comparison of construction costs of Wisconsin coal units versus inflation



The costs for Pleasant Prairie, WEPCO's most recently built coal-fired plant, along with Weston 3 and Edgewter 5, were reviewed and are shown in Table 2-2.

Table 2-2 Estimated and actual costs of recent coal-fired generating units

Plant	Estimated Cost	Actual Cost	Percent Variance
Pleasant Prairie Unit 1- 1980 (CA-5489)	$318,000,000	$411,000,000	29.2%
Pleasant Prairie Unit 2 - 1986 (CA-5489)	$264,900,000	$339,100,000	28.0%
Weston 3 - 1978 (6690-CE-1)	$240,000,000	$229,662,833	-4.2%
Edgewater 5 -1979 (6680-CE-3)	$294,600,000	$308,300,000	4.6%

Because construction costs for power plants have not increased as fast as the rate of inflation, costs on a per unit basis tend to decrease over time as the technology matures. Since 1960, advances have occurred with power technology including the ability to build larger units and the ability to obtain higher steam temperatures and pressures. During this period, emissions from coal-fired power plants have also been reduced through the burning of low sulfur Western coal, improved particulate collection, and improved combustion practices for NO_X reductions.

The cost overruns for Pleasant Prairie Unit 1 were the subject of a PSC investigation in 1981.[24] The report listed several of the factors above as reasons for the cost overrun along with the regulatory process that took 33 months to approve. The report also noted the unit was still less expensive than other units being built at that time. Factors cited for the cost overruns included:

- The time period during construction was one of high inflation and inflation was higher than anticipated.
- There was high demand for labor and materials for power plant construction.
- The costs were underestimated.
- Slippage in the planned start of construction.

The design of the Pleasant Prairie Power Plant was not finalized before the estimated costs were provided to the PSC for use in the Final Environmental Report.

PSC engineering staff believe, at this time, that the cost overrun potential for the ERGS is about 10 percent for the SCPC units and somewhat greater for the IGCC unit. Because of the recent historical trend toward cost overruns for coal-fired generation construction, staff has examined various cost overrun sensitivities when performing its analysis of the proposed ERGS project and other alternatives. A discussion of the financial and socioeconomic implications of cost overruns can be found in Chapter 4.

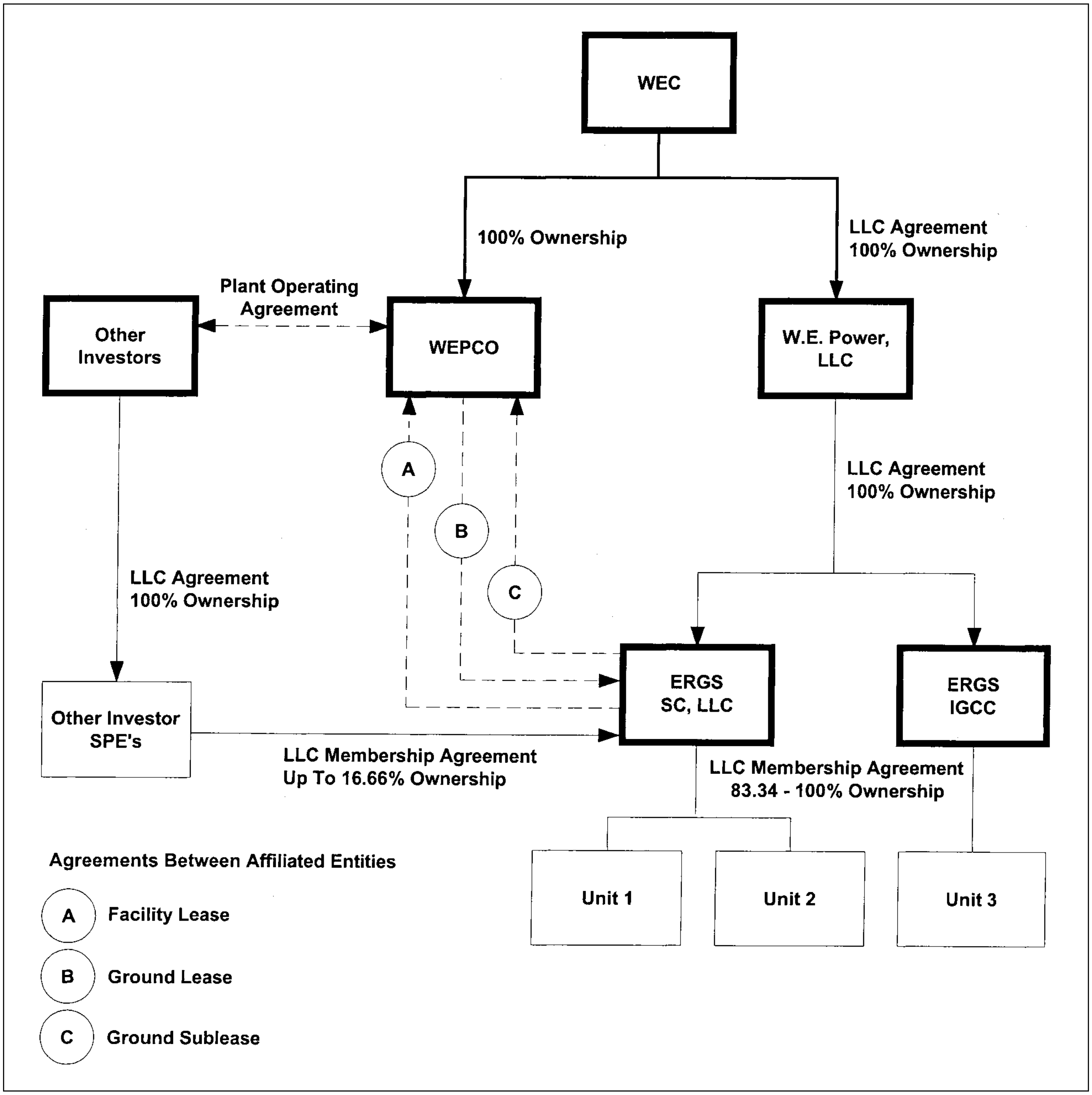
Lease Contracts

Facility lease financing

Under the leased generation approach, WEPCO would enter into long-term facility leases with two wholly owned subsidiaries of its non-utility affiliate company known as WE Power. These subsidiaries of WE Power are ERGS Supercritical LLC and ERGS IGCC LLC. The WE Power subsidiaries would construct and have major ownership interest in the facilities, but lease the generating units to WEPCO at economic terms and conditions reviewed, regulated, and approved by the PSC. Other interested utilities might have ownership interests in the facilities as well, but WE Power companies will own no less than 83 percent of each of the new generating units. WEPCO would also operate the coal facilities at the ERGS. Operation would include staffing, performing maintenance, as well as fuel procurement. The proposed facility lease for each of the proposed coal plants would have an initial term of 30 years, and WEPCO would have several options to extend the lease at a reduced rent. In addition to the facility lease there would also be several other leases covering use of the site. These other leases are referred to as ground leases and ground subleases and are discussed in sections below. The relationship between the companies and the required leases is shown in the following illustration.

[24] Final Report by Theodore Barry on Pleasant Prairie Unit 1 Cost Overruns.

Figure 2-4 Illustration of company relationships



In its May 2003 direct testimony supporting its application, WEPCO has indicated that the average construction cost of each SCPC unit would be $1,400,000 per MW in 2003 dollars. At present, WEPCO expects to take about 515 MW from each of the three 615 MW units. The remaining 100 MW of capacity for each unit is expected to be sold to Madison Gas & Electric Company (MGE) and Wisconsin Public Power Incorporated (WPPI). The estimated construction costs and WEPCO's portion of the coal plant's output translate into a $721,000,000 lease obligation in 2003 dollars for each of the SCPC units.[25] Allowing for expected annual inflation of about 2.32 percent per year turns that obligation into a $808.6 million value measured in 2008 dollars to reflect the year the first unit is expected to begin commercial operation.[26] This $808.6 million represents the principal amount per SCPC unit used in the facility lease. This value does not include retirement or management costs. It also excludes carrying costs incurred during construction. These are listed in Table 2-1. Financing costs incurred once commercial operation begins are included in the analysis that follows.

Under the facility lease, the $808.6 million principal amount per unit must be financed. In the Port Washington CPCN docket, the Commission found that the appropriate lease financing parameters were a return on equity of 12.7 percent using a capital structure containing 53 percent common equity. As for long-term debt costs, the Commission indicated that costs associated with long-term utility debt credit that is rated "A" should be used. As of June 2003 that debt cost would be 5.00 percent. Using these financing costs and a 30-year lease term indicates that the annual lease payment from WEPCO to WE Power would be $111.25 million on average for each SCPC unit. This value is calculated using an ordinary annuity formula in the following table:

Table 2-3 Lease payment calculation for the first SCPC unit at the ERGS (2008 operation date)

515	MW capacity contracted to WEPCO	
$1,400	Installed cost $/kW 2003 dollars	
2.32%	Annual GDP escalation rate	
	Lease Treatment Using PSC Approved Parameters From Port Washington CPCN Docket	
53.00%	Equity Share	
12.70%	After Tax Cost of Equity	
1.66061	Fixed Tax Rate Gross Up Factor	
47.00%	Debt Share	
5.00%	Cost of 30-Year Debt Credit Rated A	6/13/03
50.00%	Lease Extension Renewal Rate Percentage	
13.53%	Economic Cost of Capital Inclusive of Taxes	
$808.608	Principal Amount of Project (millions) 2008$	
30	Lease Term (years)	
$111.258	**Annual Rent (millions) on an annuity payment basis including MARBA adjustment**	

It is important to note that the table shown above uses the financing parameters approved by the Commission in the Port Washington CPCN docket rather than the parameters originally sought by the applicants in the ERGS application. Those parameters are an equity share for total capitalization of 58 percent earning a 12.9 percent return. Using those values in Table 2-3 would increase the annual rent to $118.9 million.

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[25] The calculation is $1,400,000\MW X 515 MW = $721,000,000.

[26] Calculated as $721,000,000 in 2003 dollars X five years compounded 2.32 percent annual inflation or $721,000,000 * [(1+.0232) ^ 5] = $808,608,000 in 2008 dollars.

It is important to note that in a July 19, 2002, agreement with the Customers First Coalition, an intervener group representing some consumer groups and utilities, WEPCO agreed to seek financing for the gas facilities at Port Washington using a 12.9 percent return on equity and 55 percent common equity in the capital structure. In the current proceeding, certain financing parameters, particularly the appropriate return on equity, will be revisited.

In the affiliated interest portion of this proceeding, docket 05-AE-118, Commission staff has suggested that a return on equity of between 11.0 and 11.4 percent would be more appropriate for the proposed facility lease for the SCPC plants should the Commission decide to use that form of financing. Using the mid-point of this range, an 11.2 percent return on equity, as well as 53 percent common equity in Table 2-3 would reduce the estimated annual rent from $111.25 million to $101.28 million.

Lastly, because computer model simulation listed in Chapter 4 shows the IGCC unit to be non-economic, Table 2-3 has not been produced in the IGCC unit. This is the reason this section focuses on the SCPC units.

Effect of facility lease on retail electric customers

Given the facility lease payment calculation shown above, it is possible to estimate the effect on ratepayers for the two SCPC plants. Together, the annual lease payments would equal about $222.5 million. Presently, the retail electric revenue requirement for WEPCO is $1.7 billion. By 2010, WEPCO's retail revenue requirement may equal $2.15 billion. This means that the additional lease payments for the first two SCPC plants at Elm Road would increase retail electric revenue requirement by about 10.3 percent by the end of 2010. For a residential customer paying about $40 per month, this means that the average customer bill would increase about $4.12 per month. (Note: this rate impact does not take into account construction of the IGCC unit.)

This estimated effect covers the construction cost component only, and it represents a proportionate increase across all customer classes. The estimate does not include carrying costs or interest during construction. In addition, the estimate does not factor in fuel expenses associated with operating the units. This latter category is difficult to estimate because while fuel expenses would increase due to the new SCPC plants, system dispatch may reduce fuel expenses at other existing generating units. Demand growth also affects the calculation because increases in demand increase fuel expense. However, the increased demand also allows the extra fuel costs to be spread over the increased demand, thereby reducing the average effect on retail rates. Due to this complexity, the above price effect on customers focuses only on the capital component of the lease associated with construction.

As a final caveat, to the extent WEPCO is able to sell excess capacity from the unit when its native load customers do not require the power, revenue from the sales would be credited back to customers during ratemaking, thus reducing the above 10.3 percent electric rate increase estimate.

Facility lease versus a traditional rate-making approach

One of the reasons a leasing approach for the coal plants was pursued, according to WEC, is that WEPCO would unlikely be allowed sufficient return on a traditional rate-base investment to compensate investors for the risks associated with the coal plants. Under traditional rate-making procedures, the utility both owns and operates the plants. Under traditional rate-making, the value of the power plant put in service is 1) placed into a utility's rate base representing accumulated capital investment in generation and distribution assets, 2) authorized a return on equity, and 3) depreciated over its estimated useful economic life. At present, WEPCO receives an authorized return of 12.2 percent for its rate-based generation and distribution assets. The useful life of a coal plant for accounting purposes is likely to be in the 40- to 50-year time frame.

In the Port Washington CPCN docket the Commission found that the historical rate-based approach was feasible, but that based on the evidence presented in that case, a leased generation financing approach was in the public interest.[27] The Commission's determination was based on the financial parameters it selected for the facility lease, other terms and conditions selected by the Commission, as well as the fact that under the Port Washington facility lease, WEPCO would operate and maintain the plant, thus remaining a regulated entity under the PSC's legal jurisdiction.

Whether this project should be financed through leases is an important issue. It is expected that the Commission will once again review whether the leasing approach or the traditional rate-base approach is the appropriate financing and ownership vehicle for the ERGS coal facilities. It is important to note recent developments favoring rate base treatment for new coal facilities. In May 2003, the Iowa Utilities Board approved a ratemaking approach for a new 790 MW coal facility for MidAmerican Energy Company to be located at Council Bluffs, Iowa. Also, as part of a requested declaratory ruling Wisconsin Public Service Corporation has indicated that it would use rate base treatment for a proposed new coal facility to be located at its Weston generating station.

The following analysis demonstrates cost streams associated with the proposed lease approach for the first SCPC unit at Elm Road versus using historical rate-making in which WEPCO would own the coal plants outright. In the rate-making example, all assumptions are the same as for the leasing method except for the return on equity and the project life. The modeled value for the traditional rate-making approach uses 13.7 percent for the rate of return on equity in order to reflect that the rate-based approach may be more expensive on a risk-adjusted basis due to potential variability of the authorized return on equity.[28] This is unlike the approach in the facility lease where the authorized 12.7 percent return on equity in the facility lease would be held fixed for the duration of the facility lease. In terms of project life, the facility lease uses the assumption of a 30-year initial term with a ten-year extension in which rent is only 50 percent of the original lease payment. In the rate-making method, the life of the project is 40 years and standard depreciation is used.

The following analysis also uses an 8.97 percent rate of discount. Under the assumption of 2.32 percent inflation, the implicit real rate of discount is 6.5 percent. This 6.5 percent value is somewhat higher than the 5.5 percent real rate of discount that the Commission had authorized for use in Advance Plan 8. A slightly higher rate favors current ratepayer and investor interests. Using a lower rate would better factor in future generations. However, the somewhat higher rate was used here to better taken into consideration potential investor interests since the Commission, as part of this proceeding, must also choose between either the facility lease or ratemaking finance method. Such a choice strongly affects the ability to finance a project.

[27] Page 25, Final Order in Docket 05-CE-117

[28] In a traditional rate-making approach, the utility's return of equity is periodically reviewed by the Commission and adjusted according to current financial trends.

Table 2-4 Comparison of cost streams using facility lease and traditional rate-making practice

515	**Contract Capacity to WEPCO in Megawatts**
$1,400	**Installed Cost $/kW 2003$ SCPC**
2.32%	**Annual GDP Escalation Rate**
8.97%	**Nominal Discount Rate**

	LEASE TREATMENT		RATEBASE TREATMENT WITH 13.7% ROE
53.00%	**Equity Share**	53.00%	**Equity Share**
12.70%	**After Tax Cost of Equity**	13.70%	**After Tax Cost of Equity**
1.66061	**Fixed Tax Rate Gross Up Factor**	1.66061	**Fixed Tax Rate Gross Up Factor**
47.00%	**Debt Share**	47.00%	**Debt Share**
5.00%	**Cost of 30-Year Debt Credit Rated A 6/13/03**	5.00%	**Cost of 30-Year Debt Credit Rated A 6/13/03**
50.00%	**Lease Extension Renewal Rate Percentage**	40	**Book Life (Years)**
		30	**Tax Life (Years)**
13.53%	**Economic Cost of Capital Inclusive of Taxes**	14.41%	**Economic Cost of Capital Inclusive of Taxes**
$808.608	**Principal Amount of Project (millions) 2008$**	$808.608	**Principal Amount of Project (millions) 2008$**
30	**Lease Term (years)**		
$9.279	**Monthly Rent Annuity Basis (millions)**		
$111.258	**Annual Rent (millions) with 99.915% MARBA Adjustment**		

First 30 Years Analysis

Year	Annual Rent Millions	Discount Factor	2003 Present Value	Year	Annual Revenue Requirement	Discount Factor	2003 Present Value
2008	$111.258	0.6508	$72.410	2008	$136.716	0.6508	$88.979
2009	$111.258	0.5973	$66.449	2009	$133.224	0.5973	$79.569
2010	$111.258	0.5481	$60.979	2010	$128.125	0.5481	$70.224
2011	$111.258	0.5030	$55.960	2011	$123.276	0.5030	$62.005
2012	$111.258	0.4616	$51.353	2012	$118.660	0.4616	$54.770
2013	$111.258	0.4236	$47.126	2013	$114.258	0.4236	$48.397
2014	$111.258	0.3887	$43.247	2014	$110.055	0.3887	$42.779
2015	$111.258	0.3567	$39.687	2015	$106.036	0.3567	$37.824
2016	$111.258	0.3273	$36.420	2016	$102.186	0.3273	$33.450
2017	$111.258	0.3004	$33.422	2017	$98.364	0.3004	$29.549
2018	$111.258	0.2757	$30.671	2018	$94.543	0.2757	$26.063
2019	$111.258	0.2530	$28.146	2019	$90.721	0.2530	$22.951
2020	$111.258	0.2322	$25.829	2020	$86.900	0.2322	$20.174
2021	$111.258	0.2130	$23.703	2021	$83.078	0.2130	$17.700
2022	$111.258	0.1955	$21.752	2022	$79.257	0.1955	$15.495
2023	$111.258	0.1794	$19.962	2023	$75.435	0.1794	$13.534
2024	$111.258	0.1646	$18.318	2024	$71.614	0.1646	$11.791
2025	$111.258	0.1511	$16.810	2025	$67.792	0.1511	$10.243
2026	$111.258	0.1387	$15.427	2026	$63.970	0.1387	$8.870
2027	$111.258	0.1272	$14.157	2027	$60.149	0.1272	$7.653
2028	$111.258	0.1168	$12.991	2028	$56.327	0.1168	$6.577

2029	$111.258	0.1072	$11.922	2029	$53.539	0.1072	$5.737	
2030	$111.258	0.0983	$10.941	2030	$51.785	0.0983	$5.092	
2031	$111.258	0.0902	$10.040	2031	$50.032	0.0902	$4.515	
2032	$111.258	0.0828	$9.214	2032	$48.278	0.0828	$3.998	
2033	$111.258	0.0760	$8.455	2033	$46.524	0.0760	$3.536	
2034	$111.258	0.0697	$7.759	2034	$44.770	0.0697	$3.122	
2035	$111.258	0.0640	$7.120	2035	$43.016	0.0640	$2.753	
2036	$111.258	0.0587	$6.534	2036	$41.262	0.0587	$2.423	
2037	$111.258	0.0539	$5.996	2037	$39.508	0.0539	$2.129	
		PV for 2008-2037	$849.225			PV for 2008-2037	$741.903	-12.6%

10 Year Lease Extension @50% of Prior Rent				**Ongoing Ratebase Treatment for Next 10 Years**				
Year	**Rent**	**Discount Factor**	**2003 Present Value**	**Year**	**Annual Revenue Requirement**	**Discount Factor**	**2003 Present Value**	
2038	$55.629	0.0495	$2.751	2038	$37.754	0.0495	$1.867	
2039	$55.629	0.0454	$2.525	2039	$36.000	0.0454	$1.634	
2040	$55.629	0.0417	$2.317	2040	$34.246	0.0417	$1.426	
2041	$55.629	0.0382	$2.126	2041	$32.493	0.0382	$1.242	
2042	$55.629	0.0351	$1.951	2042	$30.739	0.0351	$1.078	
2043	$55.629	0.0322	$1.791	2043	$28.985	0.0322	$0.933	
2044	$55.629	0.0295	$1.643	2044	$27.231	0.0295	$0.804	
2045	$55.629	0.0271	$1.508	2045	$25.477	0.0271	$0.691	
2046	$55.629	0.0249	$1.384	2046	$23.723	0.0249	$0.590	
2047	$55.629	0.0228	$1.270	2047	$21.969	0.0228	$0.502	
		PV for 2038-2047	$19.267			PV for 2038-2047	$10.768	
40 Year Analysis				**40 Year Analysis**				
		PV for 2008-2047	$868.492			PV for 2008-2047	$752.671	-13.3%

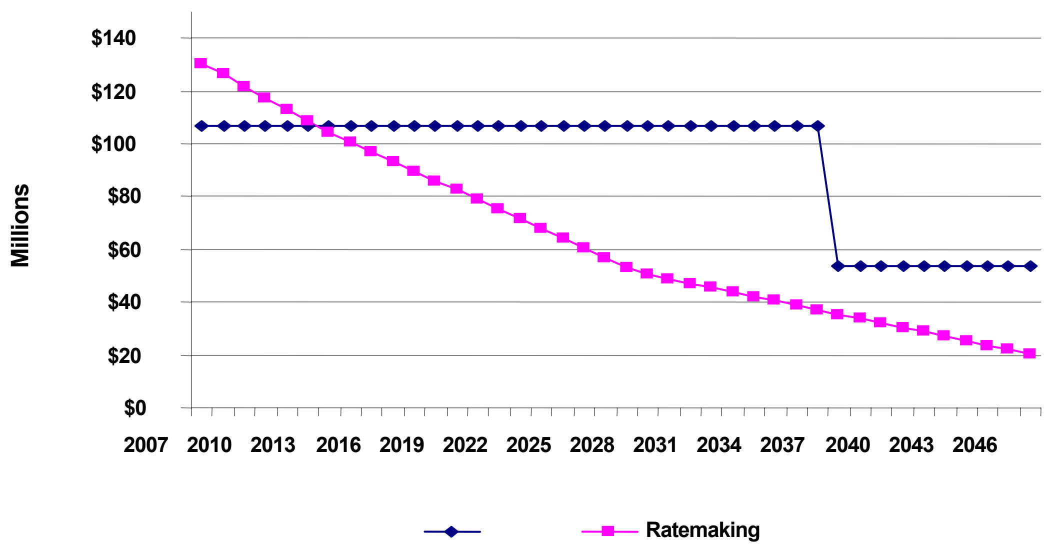
The analysis in the table above shows that a traditional rate-making approach would cost ratepayers about 13 percent less on a present value basis than using the proposed lease financing mechanism. For 40 years of operation, the present value of the lease approach is $868 million in 2003 dollars as compared to $753 million using traditional rate-making procedures. This difference would occur if the rate-based coal generation projects could be financed at a common equity rate of 13.7 percent assumed in the analysis. Whether this is the case will be examined during technical hearing in this docket, but it is important to note that the 13.7 percent rate assumed in the above analysis nearly matches the authorized rate of 13.75 percent granted to Alabama Power Company in 2002 by the Alabama Public Utility Commission. According to the utility trade publication, Public Utilities Fortnightly,[29] the 13.75 percent authorized return for Alabama Power Company was the highest authorized return for electric rate base assets in the country during 2002. However, such a value could be on the high side as MidAmerican Energy Company in Iowa in May 2003 agreed to accept a 12.29 percent return on equity in a traditional rate making financing approach for its

[29] "Return on Equity: Interest Rates Push Down Allowances," by Phillip S. Cross, Public Utilities Fortnightly, November 15, 2002.

proposed 790 MW coal facility in Council Bluffs, Iowa. Using such a value in the above table with traditional ratemaking for ERGS would save ratepayers about 19 percent on a present value basis over the facility lease.

While the rate-base calculation above is less cost than the facility lease method on a present value basis, there are important intergeneration equity aspects that may favor the lease. This is because under the facility lease, the annual rent would be $111.25 million per year on average per SCPC unit for the first 30 years, while under traditional rate making procedure using a 13.7 percent return on equity, the revenue requirement would start out much higher at $137 million and then gradually decline to around $39 million during the same period. This means that under traditional rate-making, current customers would pay relatively more for the plant than future customers would. The following chart depicts the required revenue streams under the facility lease approach and traditional rate making:

Figure 2-5 Comparison of facility lease and ratemaking annual cost streams for a SCPC unit



Cost Impact of Recent Agreement Between WEPCO and the City of Oak Creek

On March 25, 2003, the city of Oak Creek and WEPCO entered into an agreement by which:

1. Total emissions of all of the OCPP and ERGS power plants, old and new, are not to exceed year 2000 levels.
2. WEPCO agrees to install two new emissions monitoring stations.
3. WEPCO agrees to annually pay the city of Oak Creek $1.5 million at the start-up of ERGS unit 1, $750,000 at the start-up of ERGS unit 2, and $250,000 at the start-up of ERGS unit 3.
4. WisPark agrees to work with the city of Oak Creek to identify and develop areas for commercial/industrial parks and commits to investing $20 million.

5. WEPCO will work with the city on a conditional use permit basis to minimize concerns of the city of Oak Creek.[30]

Under this arrangement, the city of Oak Creek would drop its opposition to the ERGS project, and WEPCO would seek Commission approval to recover the costs of these annual community impact payments from ratepayers. Such payments would total $2.5 million after the third unit is commercially operational. The first annual payment of $1.5 million would increase the cost of the facility lease for the first SCPC unit by about 1.3 percent based on an annual estimated lease payment of $111.25 million. The effect of such payment would be less than $0.54 per month for an average residential customer. The Commission approved such payments to the city of Port Washington for the two recently approved 545 MW gas-fired combined-cycle generating plants to be constructed in that city. Whether these payments should be recovered and what is the appropriate level may be key issues at hearing in this case. In July 2003, the governor withed into law a new method for compensating communities that host new power plants. By the hearings the Commission will know the full implications of the new statute, and how it affects ERGS and the estimated ratepayer impacts.

Ground leases

Under the respective Ground Leases, WEPCO would lease land known as the Elm Road Site to ERGS, LLC, for the purpose of site access, construction, use, and operation and maintenance of each generating facility.

Upon completion of construction, the Elm Road Site would be subleased back to WEPCO to allow it to operate the completed facility as provided in the Facility Lease.

[30] The conditional use permit (CUP), signed on June ___, 2003, resulted in another proposed site layout for the ERGS facilities on the North Site. This layout and the potential environmental effects of the new layout are described in Chapter 12.